
Appendix A – WDT692



Queue Cluster 4 Phase I Report

December 31, 2011

This study has been completed in coordination with CAISO per CAISO Tariff Appendix Y Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window

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Attachments:

1. Not Used
2. Not Used
3. Not Used
4. Short Circuit Calculation Study Results (see Appendix H of the Group Report)
5. Deliverability Assessment Results (see Appendix I of the Group Report)

1. Executive Summary

[REDACTED] has submitted a completed Interconnection Request (IR) to the Southern California Edison Company (SCE) for their proposed [REDACTED] (Project) under the terms of SCE's Wholesale Distribution Access Tariff (WDAT). The Project is full capacity comprised of photovoltaic modules with an output of 10 MW. Per the study agreement, the applicant requested a Point of Interconnection (POI) on SCE's Lucerne 12kV line out of [REDACTED]. However, due to the existing queued generation on the Forage 12kV line and the limitations set by SCE's distribution design standards for generator interconnections, it was not feasible to interconnect this Project to the Lucerne 12kV line. SCE evaluated other methods of interconnections and concluded that a New 12 kV distribution circuit out of Piute Substation is required to interconnect this Project. The Interconnection Customer's (IC) requested Commercial Operation Date of the Project is [REDACTED].

Pursuant to the Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), including Appendix 8 of the GIP (Transition of Existing SGIP Interconnection Requests to the GIP) under the terms of SCE's WDAT, the Project was grouped with the Queue Cluster 4 (QC4) Phase I study (Phase I) projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid and SCE's distribution system.

The Group Report has been prepared separately identifying the combined impacts of all Phase I projects on the CAISO Controlled Grid. This report focuses only on the impacts of the Project.

The report provides the following:

1. Transmission and Distribution system impacts caused by the Project;
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions and;
3. A list of required facilities and a non-binding, good faith estimate of the Project's cost responsibility and time to construct these facilities.

The Phase I study was performed to determine problems for which mitigation plans may be proposed for the Project. Mitigation plans for the Project are detailed in Section 10 of this report.

The non-binding SCE cost estimates^{1,2} to interconnect the Project are:

Interconnection Facilities ³	\$5.269 M
Distribution Upgrades	\$0

¹ These upgrades are not reimbursable.

² Includes Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate. Due to the enactment of H.R. 4853, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CIAC recorded or received after September 8, 2010 through December 31, 2011.

³ The electrical facilities installed and maintained by SCE necessary to physically and electrically interconnect the Project to the SCE Distribution system from the point of change in ownership to the point of interconnection.

Shared Distribution Upgrades

\$9.947 M

The cost estimate for Delivery Network Upgrades based on the CAISO methodology used as part of the QC4 Phase 1 studies is \$7,418,100 (10MW X \$741,810/MW)⁴. The cost estimate for Reliability Network Upgrades due to Full Capacity Deliverability Status is \$12,000.

The estimated costs above have been provided in 2011 constant dollars. Table 10.1 provides the estimated costs escalated to the estimated Operating Date year of the upgrade, which would be the basis for the ICs financial responsibilities.

The non-binding schedule to license, engineer, and construct the Interconnection Facilities, Distribution Upgrades, and Reliability Network Upgrades is approximately 88 months from the signing of the Generator Interconnection Agreement and from SCE specified milestones associated with applicant responsibilities. The schedule to license, engineer, and construct the Delivery Network Upgrades will be addressed in the Phase II study. Based on the Queue Cluster 3 (QC3) Phase I group report, the schedule to license, engineer, and construct the Delivery Network Upgrades that were the basis of the Delivery Network Upgrade cost estimate provided above is approximately 84 months upon authorization to proceed.

2. Project and Interconnection Information

Table 2-1 provides general information about the Project as shown in the customer's IR.

Table 2-1: [REDACTED] Project General Information

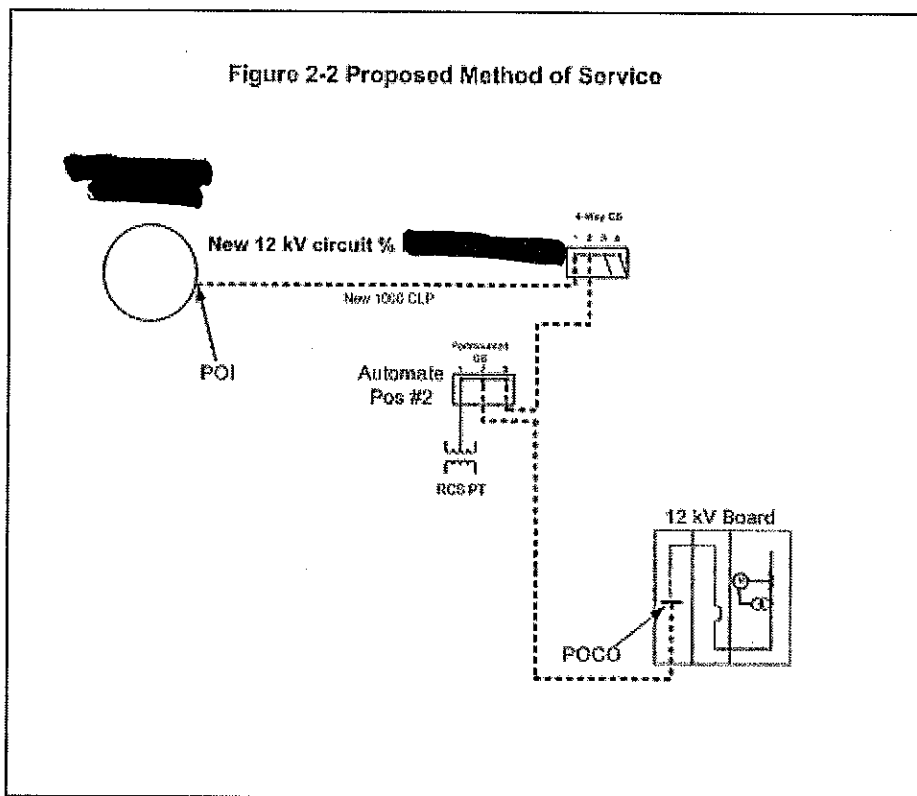
Project Location	Lancaster, CA
SCE Planning Area	Northern
Number and Type of Generators	[REDACTED] inverter type generating units, using PV technology (each rated for 500 kW)
Interconnection Voltage	12 kV
Maximum Generator Output	10 MW
Generator Auxiliary Load	0 MW
Maximum Net Output to Grid	10 MW
Power Factor Range	0.95 Lagging to 0.95 Leading
Step-up Transformer	[REDACTED] transformer rated for 12kV/265kV 1 MVA with 5.75% impedance on a 1 MVA base.
Point of Interconnection	New Dedicated 12kV circuit out of Piute Substation
Commercial Operation Date	[REDACTED] (customer requested date) ⁵

⁴ The CAISO developed the dollar/MW value based on nominal dollars.

⁵ The actual OD will be a function of the time to construct the required Transmission Network Upgrades, Distribution Upgrades, Interconnection Facilities, any other required facilities to interconnect the Project, and the GIA execution period.

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Figure 2-2: Proposed Single Line Diagram



3. Study Assumptions

For detailed assumptions, please refer to the Group Report. The following assumptions are only specific to the Project.

A. The following SCE Distribution System Planning Criteria and Conditions were included in the Phase I study:

- The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its normal rated capacity with all facilities in service (base case).
- The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its emergency rating under N-1 conditions.
- Operational flexibility and reliability of the distribution system shall be maintained at all times.
- Circuit voltage profiles should be maintained to comply within CPUC's Rule 2 requirements.
- The power factor for the new generation facility was assumed to be within WDAT requirements of 0.95 lagging or leading.
- Expected loading on the distribution system as projected by the SCE 2011 - 2020 distribution system plan was used.

- Distributed Generation resources connected to the distribution system are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine worst case scenario.
- The Short circuit contribution from the inverter systems was determined using inverter manufacturer datasheets.
- The Phase I study assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as in-service, are included in the base case for the Phase I projects.
- Current distribution standards are being updated to address generation interconnection systems. The proposed method of service in this report may change according on final design to comply with the updated distribution design standards.
- Table 3-1 shows the generation queue at Piute Substation assumed for the QC4 Phase I study.

Table 3-1: [REDACTED]

Total generation Pre QC4 on Piute Sub	[REDACTED]
Total generation QC4 on Piute Sub	[REDACTED]
Total generation at Piute Sub Post QC 4	[REDACTED]

B. The following Facilities were estimated and included in the Phase I study:

- Install approximately 12,465 feet of new 1000 CLP creating a new 12 kV distribution circuit originating at Piute 66/12 kV Substation
- Equip a new 12 kV breaker at Piute 66/12 kV Substation
- Approximately 250 feet of primary cable (1000 XLP)
- Switch Automation
- 3-way Pad Mounted Gas Switch
- 12 kV Metering, CTs, PTs, and associated wiring
- Remote Terminal Unit
- Telecommunication System for RTU
- Replace (2) 3 phase 14 MVA 66/12 kV transformers with (2) 3 phase 28 MVA 66/12 kV transformers with LTC.
- Install 1- 4.8 MVAR Capacitor Bank.
- Add three bi-directional WATT transducers on a 12kV line
- Replace Circuit Breakers at various substations

C. The following facilities are to be installed by the Interconnection Customer and are not included in this Phase I study:

- Ducts
- Structures
- Point of Interconnection Breaker
- CAISO metering as required
- Protection Systems required to comply with SCE Interconnection requirements
- Transformation as required
- Metering Equipment compliant with SCE Electrical Service Requirements (<http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm>)

4. Deliverability Assessment

The deliverability assessment for this project was performed utilizing the alternative methodology discussed and adopted by the CAISO and the stakeholders. The details of the deliverability assessment analysis are provided in the group report.

Based on the CAISO alternative methodology, the QC3 Delivery Network Upgrades and costs were carried forward to the QC4. The Delivery Network Upgrades for the SCE Northern Bulk System include the upgrades required for peak and off-peak deliverability. The per-MW costs are \$44,470/MW for peak Delivery Network Upgrades and \$697,340/MW for off-peak Delivery Network Upgrades. The Project is assigned both peak and off-peak delivery upgrade costs. The total Delivery Network Upgrade cost assigned to the Project is \$7,418,100.

5. Power Flow Analysis

5.1 Transmission System – 220 kV and 500 kV

The transmission system is not sufficient to accommodate all the generation in the area. This conclusion was reached in the QC3 study. With the addition of more generation projects in QC4, system loadings will only increase thereby requiring system upgrades to address the incremental system overloads. However, the use of the Alternative Methodology limits the total output from the generators in the area to what has been studied in the QC3 Phase I study. Therefore, the same conceptual network upgrades are proposed in this study as in the QC3 Phase I study. For reference, a summary of the network upgrades is provided below. The details of the analysis and overload levels are provided in the group study.

5.1.1 QC3 Recommended Mitigations Used to Derive Dollar-per-MW Value

- North and South of Magunden 230 kV T/L upgrades
- Kramer-Windhub 500 kV T/L
- Mesa 500 kV Upgrades
- PG&E Upgrades Allocated to Northern Bulk System Projects

5.2 Subtransmission System – 66 kV

The Subtransmission system is not sufficient to accommodate all the new QC4 generation projects in the area. The reliability assessment has identified system issues with the addition of the QC4 Phase I Projects interconnecting in the Northern Area 66kV Subtransmission level. Please refer to Section 7 and Section 11 of the group report for the Subtransmission power flow study results and mitigations discussion, respectively.

5.3 Distribution System – 34.5kV or Below

The Phase I distribution study indicated that the Project contributes to the following distribution facility overloads:

5.3.1 Overloaded Distribution Facilities

- Under base case condition, without the QC4 projects in service, the (2) 14 MVA 66/12kV transformers at [REDACTED] are loaded to 58.9% of its normal rating. With the proposed 12kV QC4 projects at [REDACTED] in service during base case conditions, the [REDACTED] 14 MVA 66/12 kV transformers at [REDACTED] become overloaded to 108.9% of the transformers normal rating.

5.3.2 Recommended Distribution Mitigations

- Replace [REDACTED] 3 phase 14 MVA 66/12 kV transformers with [REDACTED] 3 phase 28 MVA 66/12 kV transformers.

The new 12kV circuit will experience power flow back into the 12kV bus during minimum loading and maximum generation conditions. As a result of the reverse power flow in a distribution system designed to monitor power flow from the 12kV bus towards the loads, Watt transducers are required on the new 12kV line for operational purposes.

6. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the transmission and distribution system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase I is determined. Each project in Phase I will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

6.1 Short Circuit Study Input Data

The customer provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrates differences in the SCD parameters, then SCE utilized the manufacturer data of the inverter model specified by the IC in the application in the SCD study. Otherwise, SCE utilized the parameters provided by the IC. The IC should verify with the manufacturer the appropriate SCD contributions of the inverter prior to commencement of the Phase II study and should update the application to reflect the appropriate data. The data provided by the IC for this project did not match the technical data obtained from the inverter manufacturer.

The following input data was used in this study:

Short Circuit Data @ 10 MVA Base:

- Positive Sequence subtransient reactance (X''1) = 1.0 p.u.
- Negative Sequence subtransient reactance (X''2) = 1.0 p.u.
- Zero Sequence subtransient reactance (X''0) = 1.0 p.u.

Generation Step-up Transformer(s)

Individual Padmount Transformer Data (total of 10):

Each transformer is three-phase 12.0 kV/0.265 kV (D-Y) rated for 1.0 MVA with the following impedance information:

- Impedance Value: 5.75 % @ 1.0 MVA

6.2 Results

All bus locations where the Phase I projects increase the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in the Group Report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the Phase I interconnections and corresponding distribution and network upgrades, if any.

The responsibility to finance short-circuit duty related Distribution Upgrades and Reliability Network Upgrades identified through a group study shall be assigned to all Interconnection Requests in that group study pro rata on the basis of short-circuit duty contribution of each Generating Facility. In addition, the SCD impact of the associated proposed Distribution and Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Distribution and Network Upgrade.

As discussed in the Group Report, the Phase I breaker evaluation identified overstressed circuit breakers at the following buses. The cost allocation for this project, based on SCD contribution at each location, is also provided:

SCD Mitigation – Table of Network Breaker Upgrades

Project	Valley 500kV		Antelope 220kV		Colorado River 220kV		Kramer 220kV		Redondo 220kV		Vista 220kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT692	0.01	\$0	0.16	\$1	0	\$0	0.06	\$3	0.09	\$7	0.04	\$2

SCD Mitigation – Table of Distribution Breaker Upgrades

Project	Garnet 115 kV		Inyokern 115 kV		Lancaster 12 kV		Piute 12 kV		Victorville 4 kV		Vista 66 kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT692	0.01	\$0	0.02	\$0	2.26	\$34	3.03	\$1	68.5	\$673	0	\$0

6.3 Preliminary Protection Requirements

Protection requirements are designed and intended to protect SCE's system only. The preliminary protection requirements were based upon the interconnection plan as shown in Figure 2-2.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook provided as an attachment to the group report.

7. Reactive Power Deficiency Analysis

7.1 Group Study Reactive Power Deficiency Results

Following the alternative methodology, the reactive power deficiency conclusions were based on the analysis performed for the QC3 Phase I Projects.

The QC3 Phase I study demonstrated that the QC3 Phase I Projects collectively contribute to reactive power deficiencies in the transmission system under base case and contingency conditions, and voltage criteria violations under contingency conditions. The study concluded that construction of a combination of additional transmission facilities and reactive support devices will be required.

It is expected that the addition of the QC4 projects will further exacerbate the problematic system conditions identified in the QC3 Phase I study. These issues will be fully evaluated in a more detailed reactive power deficiency analysis to be performed as part of the Phase II study.

7.2 Individual Project Power Factor Requirements

The project is required to provide 0.95 leading/lagging power factor regulation at the POI. Applicant should be design interconnection facility to accept an SCE's VAR Schedule in accordance with the VAR requirements of the SCE's electrical distribution system configuration. The VAR schedule may change in the future as a function of distribution system reconfigurations

7.3 Distribution

The new distribution 12 kV circuit is not expected to experience a voltage rise which would exceed the allowable Rule 2 requirements at [REDACTED] 12 kV bus with the project in service.

8. Transient Stability Evaluations

Please see Section 9 and 10 of Group Report.

9. Environmental Evaluation/Permitting

Please see Section 12 of Group Report.

10. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Phase I, the CAISO developed cost allocation factors based on the individual contribution of each project. The cost allocation for the Interconnection Facilities, Network Upgrades, and Distribution Upgrades for which the Project is solely responsible is as follows:

PTO'S INTERCONNECTION FACILITIES

1. Distribution:

- Install approximately 12,465 feet of new 1000 CLP creating a new 12 kV distribution line circuit originating at Piute 66/12 kV Substation
- Equip a new 12 kV breaker at Piute 66/12 kV Substation
- Approximately 250 feet of primary cable (1000 XLP)
- Switch Automation
- 3-way Pad Mounted Gas Switch
- 12 kV Metering, CTs, PTs, and associated wiring
- Remote Terminal Unit
- Telecommunication System for RTU

2. Telecommunications

It is assumed that the local phone company can provide a T1 service to the project location. If local phone company cannot provide T1 line service, then cost for telecommunication may increase.

3. Metering Services Organization

Install revenue metering cabinet for the SCE revenue meters required to meter the retail load at the generating facility. The SCE meter will be installed in tandem with the ISO meter circuit.

4. Power System Control

It will be required to install one RTU at the generating facility to monitor Watts and VAR flow, CB status, Voltage, etc.

5. Real Properties

It is assumed that applicant will provide all rights of way, and easements satisfactory for installation of SCE facilities without cost to SCE, based on Edison's design.

6. Corporate Environmental Health & Safety Organization

It is assumed that all SCE facilities will be included within the Generator's Environmental Licensing and Permits. There may be a need to include additional Edison Facilities within the permitting process, once Edison starts the design.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

There were no Plan of Service Reliability Network Upgrade costs allocated to the Project.

RELIABILITY NETWORK UPGRADES

Transmission Network Circuit Breaker Upgrades (SCD)

Upgrade transmission network circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

- Install [REDACTED] sets of 500 kV TRV capacitors at Valley Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Antelope Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Colorado River Substation
- Replace [REDACTED] 220 kV CB's at Kramer Substation
- Replace [REDACTED] 220 kV CB's at Redondo Substation
- Install [REDACTED] sets of 220 kV TRV capacitors at Vista Substation

See the Group Report for additional details

DELIVERY NETWORK UPGRADES

QC3 Recommended Mitigations Used to Derive Dollar-per-MW Value:

- North and South of Magunden 230 kV T/L upgrades
- Kramer-Windhub 500 kV T/L
- Mesa 500 kV Upgrades
- PG&E Upgrades Allocated to Northern Bulk System Projects

See the Group Report for additional details.

DISTRIBUTION UPGRADES

1. Subtransmission

- Rebuild a portion of the Lancaster – Purify - Redman 66 kV Line from Collector Substation 2 to Q850 Substation
- New 500/220/66 kV Substation and subtransmission system reconfiguration
- Del Sur Substation Expansion and subtransmission system re-configuration

See the Group Report for additional details.

2. Distribution

None

3. Substation – Shared with other customers based on MW

- Replace (2) 3 phase 14 MVA 66/12 kV transformers with (2) 3 phase 28 MVA 66/12 kV transformers with LTC.
- Install 1- 4.8 MVAR Capacitor Bank.
- Add three bi-directional WATT transducers on a 12kV line

4. Telecommunications

None

5. Real Properties

It is assumed that applicant will provide all rights of way, and easements satisfactory for installation of SCE facilities without cost to SCE, based on Edison's design.

6. Corporate Environmental Health & Safety Organization

It is assumed that SCE will not be required to obtain licensing and permits and will not perform or review any environmental activities other than SCE's typical environmental practices which occur during the design of the interconnection facilities and required distribution upgrades

7. Distribution Circuit Breaker Upgrades (SCD):

Upgrade distribution circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

- Replace [REDACTED] 115 kV CB's at Garnet Substation
- Replace [REDACTED] 115 kV CB's at Inyokern Substation
- Replace [REDACTED] 66 kV circuit breakers at Vista Substation
- Replace [REDACTED] 12 kV circuit breakers at Lancaster Substation
- Replace [REDACTED] 12 kV circuit breakers at Piute Substation
- Replace [REDACTED] 4 kV circuit breakers at Victorville Substation

See the Group Report for additional details

8. OTHER REQUIREMENTS

Harmonic Study Requirements

The harmonic impact of the subject inverter based generation was not part of this System Impact Study. Despite the relatively low THD (<3%) of the equipment, impacts on voltage distortion levels may be significant due to the high penetration level of the generation facility with respect to the local distribution grid strength. As with all equipment connected to the SCE distribution system, the generation project will be subject to the provisions of Rule 2.E, allowing SCE to require customer mitigation of interference with SCE service, including harmonic impacts, if harmonic interference is caused by the customer. Since the THD values which were provided are for individual inverters and not for the total generation requested, it will be required to determine the total harmonic contribution for the entire generation facility prior to approving the generation to interconnect to the SCE distribution system. Given the amount of generation and the strength of the distribution system, SCE will not require a harmonic study.

Table 10.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary
 Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.

Type of Upgrade	Upgrade (May include the following)	Description	Estimated Cost x 1,000 Constant Dollar (2011) (Note 4)	Estimated Cost x 1,000 Constant Dollar (OD Year) (Note 4)	Estimated Time to Construct
PTO's Interconnection Facilities (Note 1, 3, 5)	See Section 10 – PTO's Interconnection Facilities	Non-network facilities needed to enable interconnection	\$5,269	\$5,943	24 Months
Plan of Service Reliability Network Upgrades (Note 6)	See Section 10 – Plan of Service Reliability Network Upgrades	Direct Assigned Network Upgrades needed to enable interconnection.	\$0	\$0	n/a
Reliability Network Upgrades (Note 6)	See Section 11.2 – Reliability Network Upgrades in the Group Report	Allocated Network Upgrades needed to maintain system Reliability	\$0	\$0	n/a
Reliability Network Upgrades (Note 6)	See Section 11.2 - Reliability Network Upgrades for SCD in the Group Report	SCD Mitigation Allocated to maintain system Reliability	\$12	\$14	24 Months
Delivery Network Upgrades (Note 6)	See Section 11.3 - Delivery Network Upgrades in the Group Report	Network Upgrades needed to support Full Delivery, if requested		\$7,418.10	84 Months
Distribution Upgrades (Note 2, 5, 6)	See Section 10 – Distribution Upgrades	Non-CAISO SCE Distribution Facilities	\$9,237	\$11,332	88 Months
Distribution Upgrades (Note 2, 5, 6)	See Section 10 – Distribution Upgrade for SCD Mitigation	SCD Mitigation Allocated to maintain system Reliability	\$710	\$801	24 Months
Total Cost				\$25,508.10	88 Months

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

Note 2: These upgrades are not part of CAISO Controlled Grid, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute GIAs.

Note 3: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates.

Note 4: SCE's Phase I cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D. year. For the QC4 Phase I study, the estimated O.D. is derived by assuming the duration of the work element will begin in January 2013, which is the CAISO tariff scheduled completion date of the QC4 Phase II study plus 90 days for the GIA signing period. For instance, if a work element is estimated to

take a total of 24 months (permitting, design, procurement, and construction), then the estimated O.D. would be January 2015. If an IC's requested O.D. (in-service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used.

Note 5: Includes 35% ITCC.

Note 6: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

Cost Estimate Summary (2011 Dollars)

Scope: 10.0 MW Project proposing to interconnect to Lucerna 12kV Distribution Line out of Plute Substation

No.	ELEMENT	INTERCONNECTION FACILITIES (Subject to ITCC)	ITCC ** (35%)	TOTAL	TOTAL CONSTANT \$ (ESTIMATED YEAR O.D.)***
	Shared Substation Element				2015
1	Telecomm	\$	\$		
1	Install channel and associated equipment to support SCADA RTU circuit from GIP customer location to SCE Energy Management System	\$ 84,000	\$ 28,000	\$ 112,000	
	Distribution Engineering				
1	Install 12kV line of approx 12,315 feet of new 1000CLP cable	\$ 3,746,000	\$ 1,311,600	\$ 5,057,600	
2	12 kV Metering, CTs, PTs, and associated wiring (Cost include above)				
3	Switch Automation (Cost include above)				
4	3 Way Padmounted Gas Switch (Cost include above)				
	Power System Control				
1	RTU at Generating Facility	\$ 60,000	\$ 21,000	\$ 81,000	
Totals		\$ 3,806,000	\$ 1,360,600	\$ 5,166,600	\$ 5,943,000

* Pursuant to PERC Order 2003A, ITCC is not collected on Reliability Upgrades and One Year Costs.

** ITCC cost may be reduced with a letter of credit in accordance with the tax provisions of the GSA.

*** The ITCC included in the cost estimate was computed using a 35% rate. Because of recent enactment of H.R. 4862, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CAQs recorded or received after September 8, 2010 through December 31, 2011.

Cost estimate is only an estimate based on 2011 constant dollars and actual cost is subject to change depending on project construction data and inflation.

**** SCE's Phase I cost estimating is done in "constant" dollars 2011 and then escalated to the O.D. year. For the CCA Phase I study, the estimated O.D. is derived by assuming the duration of the work element will begin in January 2013, which is the CAISO tariff scheduled completion date of the CCA Phase I study plus 90 days for the final design period. For instance, if a work element is estimated to take a total of 24 months (permitting, design, procurement, and construction), then the estimated O.D. would be January 2015. If an IC's requested O.D. is beyond the estimated O.D. of a work element, the IC's requested O.D. is used.

This document is for informational purposes only. It is not intended to constitute an offer of insurance or any other financial product. For more information, please contact your insurance broker or agent. This document is not to be used as a basis for any legal or financial decision.

11. Items Not Covered In This Study

11.1 Conceptual Method of Service

The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Phase I Interconnection Study.

11.2 Customer's Technical Data

Additional technical data related to the Project may be required as part of the Phase I Study. The study accuracy and results for the Phase I Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the study results.

11.3 Study Impacts on Neighboring Utilities

This generation project interconnection may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

11.4 Relocations and Other Use of SCE Facilities

The Interconnection Customer is responsible for all costs associated with necessary relocation of any SCE facilities as a result of this project and acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross SCE facilities and property. The relocation of SCE facilities or use of SCE property rights shall only be permitted upon written agreement between SCE and the Interconnection Customer. Any proposed relocation of SCE facilities or use of SCE property rights may require a separate study and/or evaluation to determine whether such use may be accommodated, and any associated cost would be non-refundable.

11.5 SCE Interconnection Handbook

The Interconnection Customer shall be required to adhere to all applicable requirements in the SCE Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

11.6 Western Electricity Coordinating Council (WECC) Policies

The Interconnection Customer shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

11.7 System Protection Coordination

Adequate Protection coordination will be required between SCE-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

11.8 Standby Power and Temporary Construction Power

The Phase I study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the interconnection facilities. Should the Project require standby power or temporary construction power from SCE prior to the in-service date of the interconnection facilities, the IC is responsible to make appropriate arrangements with SCE to receive and pay for such retail service.

11.9 Construction Schedule

The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction.

Attachment 1

(Not Used)

Attachment 2

(Not Used)

Attachment 3

(Not Used)

Attachment 4

Short Circuit Calculation Study Results

Please refer to Appendix H of the Group Report.

Attachment 5

Deliverability Assessment Results

Please refer to the Appendix I of the Group report.